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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U 39 M)	Application 06-03-005 (Filed March 2, 2006)

THE DIVISION OF RATEPAYER ADVOCATES' COMMENTS IN RESPONSE TO THE ASSIGNED COMMISSIONER'S AUGUST 22, 2007 RULING REQUESTING COMMENTS ON DYNAMIC PRICING ISSUES

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I. INTRODUCTION

Pursuant to the August 22, 2007 Assigned Commissioner Ruling ("ACR") requesting comments on dynamic pricing issues, the Division of Ratepayer Advocates ("DRA") hereby provides comments on the 73 questions pertaining to rate design in Attachment A of that ACR. DRA's comments concentrate on those areas where more analysis is needed, with an emphasis on how these issues affect residential ratepayers. In these comments, DRA has provided the respective questions in their entirety for ease of reference, with the answers following.

II. DRA'S COMMENTS ON QUESTIONS IN ATTACHMENT A OF THE ACR

A. Summary of DRA Recommendations

DRA commends Commissioner Chong's goals to achieve a successful dynamic pricing policy in California as articulated in her ACR. We agree that the status quo is far from perfect. DRA indeed encourages the vigorous investigation into these issues in this proceeding but with the caveat that the eventual rollout of dynamic pricing be done on a careful and incremental basis. The state of the art of the various innovative rate designs is in its infancy, and we need more experience before any kind of mandatory tariffs are considered. Years of discussion and analysis have gone into the current tariff structures. A wholesale change at this point risks "throwing the baby out with the bath water".

DRA's position on some of the issues in the ACR is as follows:

- It strongly supports marginal cost based rate designs. It also supports departures that have been made from strict marginal cost pricing for the sake of the environmental and social goals. Promoting energy efficiency and greenhouse gas emissions reduction, which the current steeply inverted residential default rate design does, are as important, if not more important, than demand response.
- DRA strongly believes that dynamic tariffs should be voluntary at least until the AMI systems are fully deployed. Adopting dynamic rates for customers on a default or mandatory basis is also premature because the enabling equipment is not yet readily available to allow small customers to benefit from such rates.
- At this stage, because of concerns regarding potentially large bill impacts, DRA prefers programs that offer positive incentives aimed at reducing consumption at peak times.

In the discussion below, DRA has provided suggested areas of further investigation for this phase that would advance the goals of dynamic pricing for all three utilities. These areas of investigation are as follows:

- Current residential rates send a very strong energy conservation message where tail block rates vastly exceed marginal costs. More analysis is needed on the degree to which a sharply inverted tier structure is supported by environmental externalities.
- Analysis of whether the combustion turbine ("CT") proxy provides a realistic representation of what utilities actually pay for reliability would be fruitful.
- More analysis about how distribution costs vary by time period and whether and how they might be incorporated into dynamic rates is needed.
- More research into how to quantify a hedging premium is required, including how the cost of such a premium could be incorporated into flat rate tariffs.

Straw rate designs coming out of this process for the residential class should be limited to the following:

- Developing a simple peak-time rebate ("PTR") program for PG&E, leaving more complex rate designs for the future.
- Examining whether it would be feasible to time differentiate usage above tier 2 in the residential Schedule E-1 default tariff after the Advanced Metering Infrastructure ("AMI") is fully deployed.

B. Comments on Specific Issues in the Ten Sections of the ACR

1. Objectives of dynamic pricing and time-differentiated rates

DRA agrees that the main policy issue that should be decided in this phase of the proceeding is the relative importance of the three objectives in question 1 – marginal cost pricing, flattening the load curve, and making demand responsive to supply shortfalls. But beyond that, the Commission needs to decide the relative importance of dynamic pricing itself relative to other objectives embedded in existing rate design. These include promoting energy conservation (regardless of time of day)[1] and providing all residential customers "a low affordable rate" for an amount of electricity that is deemed essential to support health and safety. This baseline level was established by the legislature "observing the principle that electricity and gas are necessities" for modern life. (See Public Utilities Code Section 739 (c) (2).)

More analysis is needed that would explicitly quantify externalities that are not included in marginal costs that have been used to justify departures from marginal cost pricing. It might turn out that externality studies would not justify

[1] The energy conservation incentive is mainly provided by the increasing block rate structure in the residential class. It has been difficult to determine how to embed a similar incentive into non-residential rates since increasing block rates will not work because of the vast heterogeneity of customer sizes. It would almost require establishing a reference level for each customer, as is done in two-part RTP rates, which would not be administratively feasible for all non-residential customers.

PG&E's 36 cent/kWh tail block rate on Schedule E-1, and that some of the revenue requirement captured through that tail block rate could be captured through a dynamic component in the rate. Doing so would more accurately reflect both the Commission's energy conservation and demand response goals in the default residential rate schedule.

Question #1: What are the objectives of dynamic pricing and time-differentiated rates? How should the various objectives be prioritized? Some objectives, in no particular order of importance, are listed below:

- *Reflect marginal cost of electric service*. If the price faced by a consumer is close to the marginal cost of providing the electric service, the consumer can make efficient decisions and adjustments in usage patterns. Consumers may be able to lower their overall energy costs by reducing their electricity consumption during higher cost periods or shifting consumption from high cost to low cost periods.
- *Flatten the load curve.* The electric utility must make capital investments and contractual commitments to satisfy peak electric demand. Some of the generation, distribution, and transmission capacity is only needed during limited hours each year. Such investment may be avoided in the future if customers' rates are higher during peak hours and lower during off-peak hours, providing an incentive for customers to shift usage from peak to off-peak hours through changes in behavior and technology.
- *Reduce load in the face of short-term supply shortfall.* Unforeseen supply shortfalls can lead to involuntary curtailment of electric service to consumers. The probability of involuntary curtailment may not be reflected in the wholesale price. Tariffs that are specifically designed to reduce load in the face of supply shortfalls could help to avoid involuntary curtailment.

DRA Response: DRA strongly supports marginal cost based rate designs. It also supports departures that have been made from strict marginal cost pricing for the sake of the environmental and social goals mentioned above. Setting the individual rate elements at marginal cost would recover marginal demand and customer costs entirely through demand and customer charges respectively. Yet there is a long history of recovering costs that are relatively fixed in the short run through volumetric rates to promote energy conservation. Indeed, such rates in the residential class are also highly inverted for this purpose. This rate design furthermore protects smaller customers from the post-restructuring rate impacts.

The trend of recovering costs through volumetric rates has been extended in recent general rate cases ("GRC") by converting demand charges to volumetric charges in rates offered to solar self generation customers. There also has been a tendency to recover the entire cost of a CT through the critical peak pricing ("CPP") rate even though the loss-of-load probability ("LOLP") is not zero in the non-CPP hours. This is done to enhance the demand response beyond what would occur under strict marginal cost pricing, thus flattening the load curve.

These departures from marginal cost pricing are often justified on the basis that customer price elasticities are too small to elicit much energy conservation or demand response if one charged the marginal cost with no adjustment. It is important to note that the price elasticities themselves are revealed preferences. They reveal how customers trade off money, comfort, and the time it takes to research and install energy efficiency, demand response, and self generation measures. Thus any departure from pure marginal cost pricing is really overriding individual preferences for the sake of the common good. Such departures can also produce inter-customer subsidies. Ideally cost effectiveness evaluations of energy efficiency, demand response, and self generation should include these subsidies that are built into rates. Departures from marginal cost should be informed by the value of the externalities being used to justify these departures. Given the complexity of this kind of analysis, changes to existing rate design must be done carefully and deliberately and after much discussion.

Question #2: How should dynamic pricing policy be coordinated with other policy and rate design considerations such as energy efficiency, greenhouse gas emission reduction, rate stability, rate simplicity, cost causation, and utility cost recovery?

DRA Response: DRA believes that rate design should also support the other considerations mentioned in the question. Promoting energy efficiency and greenhouse gas emissions reduction, which the current steeply inverted residential default rate design does, is as important if not more important than demand response.

2. Rate Design Options

This section contains twelve questions that delve into a plethora of different rate options and how they should be structured and rolled out to customers. DRA believes that the Commission needs to step back before considering these rate options and determine how quickly they should be phased in. DRA favors starting slowly with the introduction of PTR into the residential class as a first step in transitioning to dynamic pricing. SDG&E and SCE have already presented PTR programs in their AMI filings. For the residential class, the "straw person" rate design proposal emanating from this proceeding should be limited to a PTR program for PG&E.

Question #1: What rate options should be offered to each type of customer, including bundled, direct access, Community Choice Aggregation (CCA), and net-metering? Dynamic rates could include some or all of the following rate strategies:

- Peak, mid peak and off-peak period time-of-use (TOU) rates.
- TOU rates that have more time periods, such as hourly.
- Real time prices (RTP).
- Pre-defined high super peak rates during critical peak periods, or Critical Peak Prices (CPP).
- Rebates during critical peak periods.
- Any other?

DRA Response: As indicated above, DRA favors beginning with PTR in the residential class. It does not favor more complex options such as real time pricing (RTP"). It is not clear that customers are ready for this because utilities have offered RTP in the past and have had very few participants. Such a rate design requires equipment that will allow an automated response to fluctuating energy prices, something that is only beginning to become available to commercial and industrial customers. There is also the complication of how the real-time price will be determined and communicated to the customer after the California Independent System Operator's ("CAISO") Market Redesign and Technology Upgrade ("MRTU") is implemented next year.[2]

[2] The real-time price will be available on the CAISO's website on a 10-minute basis almost instantaneously for dozens of different transmission nodes. The utility will probably need software to download this information and aggregate it to an hourly basis and for the nodes on which the utility takes service. Then it will have to be transmitted to the customer with as little delay as possible. Section 6 below discusses options for transmitting it.

Question #2: Which tariffs should be voluntary, default with opt-out provisions, or mandatory?

DRA Response: DRA strongly believes that dynamic tariffs should be voluntary at least until the AMI system is fully deployed. Imposing dynamic rates on some customers (who have AMI meters) and not others could be seen as discriminatory and contrary to Public Utilities Code Section 451. Adopting dynamic rates for customers on a default or mandatory basis is also premature because the enabling equipment is not yet readily available to allow small customers to benefit from such rates.

Question #3: What are the advantages and disadvantages of rebates as an alternative to rates?

DRA Response: This question is addressed at length in both the SDG&E AMI and GRC testimony.[3] The Commission should refer to this record rather than recreating it in this proceeding.

Question #4: Should automatic load control be considered as a substitute for dynamic pricing rates?

DRA Response: See the answer to Question #6 in Section 7 below.

Question #5: Should customers be offered a large variety of rate options so that customers can find a rate option that works for them, or should customers be offered a small number of options to avoid confusion, simplify marketing and minimize administrative costs?

DRA Response: The Commission's approach should be incremental. The first offerings should be relatively simple to facilitate customer education about dynamic pricing. Unfolding a large array of dynamic rate options too quickly might be confusing to customers.

Question #6: How should accuracy and simplicity be balanced in rate design?

DRA Response: Given the need for customer education, DRA would favor an initial dynamic rate offering that is relatively simple. Indeed, even a simple dynamic rate offering will provide a more accurate price signal than what now exists.

[3] See DRA Opening Testimony in A.05-03-015 (SDG&E AMI), Chapter 5 and DRA Opening Testimony in A.07-01-047 (SDG&E GRC), Chapter 6.

Question #7: How should the expected ability of a customer group to respond to time-differentiated rates be taken into consideration?

DRA Response: The goal of demand response programs is to elicit demand response. Thus designing a program necessarily requires some consideration of a customer group's ability to respond to time-differentiated rates. We don't really know whether customers will respond without first offering them a dynamic rate. Such a rate might motivate some customers to find a way to respond that wasn't initiated before. At this stage, because of concerns regarding potentially large bill impacts, DRA prefers programs that offer positive incentives aimed at reducing consumption at peak times. Eventually, dynamic rates should become the default rate regardless of whether customers respond, and those who want price certainty can purchase a hedge. Ultimately, it is important that customers receive a price signal that reflects how costs vary in time regardless of whether they respond to it.

Question #8: For customers that operate off-line and peaking generation facilities, how should the need to use system power for start-up operations be addressed?

DRA Response: None

Question #9: What is the expected response of demand to rate options, taking into account results of pilot programs and relevant studies?

DRA Response: The initial response may be modest, but even if there is no response, the dynamic rate still more accurately reflects system costs. As enabling technology improves, the magnitude of the response may increase.

Question #10: Should customers be offered bill protection during an initial time period to learn how a rate might impact their bills?

DRA Response: DRA would favor bill protection for CPP rates while customers gain experience with the rate.

Question #11: How would offering bill protection affect customers' response to dynamic pricing tariffs?

DRA Response: It is unclear how bill protection will affect customers' response. Those who seriously want to "try out" the new rate schedule will probably make a good faith effort to reduce their on-peak and critical-peak load. Others might not alter their response at all. The latter, of course, are more likely to opt out of the rate after the bill protections expire.

Question #12: What are the potential distributional impacts of dynamic pricing rates?

DRA Response: The distribution impacts of adopting dynamic rates could be significant. It is well known that coastal customers currently subsidize inland customers with large air conditioning loads. A slow and incremental approach to phasing in such rates will help phase in slowly the distributional impacts.

3. Components of dynamic pricing tariffs

A major challenge in implementing time-varying rates will be in deciding which costs vary with time. There is general agreement that generation costs vary with time, though recent changes in the wholesale market complicate the task of determining how they vary in time, as discussed in Section 6 below. There is consensus that distribution costs are affected by peak loads on the distribution system, but there is little agreement about how they should be measured or reflected in rates. This issue is discussed further in answering question # 1 below.

Further investigation of the time-varying characteristics of distribution costs in this phase of the proceeding would be useful. This analysis should also include how best to reflect these costs in residential TOU rates. Implementation of any general principles developed in this phase in marginal cost calculations would have to take place in the individual company GRCs. These revised marginal costs would be needed before any rate design could be done.

Question #1: Which utility costs vary over time, vary with volume delivered, vary with demand, and/or are fixed? Which utility costs are fixed in the short run, but vary in the long-run?

DRA Response: There is generally consensus that generation costs vary over time. There is consensus that distribution costs also vary over time, but there is little understanding of how they vary. For revenue allocation purposes, the three utilities measure loads on the distribution system in different ways.[4] The

[4] PG&E uses a measure called "peak capacity allocation factors", SCE uses what it calls "effective demand", and SDG&E uses a weighted average of coincident and non-coincident

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extent to which they are included in non-coincident demand charges also varies between utilities.

Up until now, it has been impossible to reflect in residential rates a non-coincident demand charge. Even with AMI, there are no plans to keep track of customers' non-coincident demands, though it could be possible theoretically. Including these costs in energy charges is problematic because the distribution system does not necessarily peak exactly at the same time as does the generation system. But it may be possible to assign some of the distribution costs to whatever time-of-use ("TOU") period best matches the time when residential customers in aggregate draw their highest demand.[5]

Question #2: What costs should be recovered through the time-variant portion of the rate?

DRA Response: In general, costs that are deemed time-varying should be recovered through the time-varying rate. However, the actual rates derived in this manner may not invoke the kind of demand response the Commission is looking for. Thus, costs that are relatively more fixed, as well as the effects of the EPMC multiplier, could be included in time-varying rates. But doing so would cause changes in actual revenues produced by dynamic rates to diverge more from changes in cost brought about through demand response. This would require regulatory mechanisms to assure revenue stability (See Section 4 below.)

Question #3: How should time variant costs be determined?

DRA Response: This is a complex issue that is affected by how the wholesale market reflects time-varying costs (see Section 6 below) and how distribution costs vary with time (see question #1 above).

Question #4: What is the appropriate time granularity for measuring electric service costs in connection with dynamic rate design—annual, monthly, weekly, daily, hourly, ten minutes, etc.?

DRA Response: Most customers can only deal with a fairly low level of granularity (daily and TOU periods). Introduction of enabling equipment will

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demand.

[5] Loads at the generation system peak merely reflect a higher level of diversity than they do at the distribution level. Thus when the distribution system peaks is not unrelated to when the generation system peaks. Understanding this relationship better might help determine how much of the distribution costs could be reflected in time varying rates for the residential class.

allow customers to react to a lower level of granularity (up to hourly). The non-residential AMI meters will be capable of 15-minute granularity, but not 10-minute. The CAISO performs settlements on a 10 minute interval. Thus it is obvious that whatever the maximum granularity chosen is, it will have to be a whole multiple of both 10 minutes and 15 minutes. A half-hour is the maximum granularity that would accommodate both the CAISO and the capability of the AMI meters. But customers may prefer merely using one-hour increments.

Question #5: How closely should the time profile of dynamic rates be aligned with the time profile of service costs?

DRA Response: Ideally one would want to design rates that exactly match how those costs vary in time. Doing so has the greatest likelihood of tracking changes in the revenue requirement over time (Section 4, Question #1). Thus fixed costs would not be included in time varying rates (Question #8). Nor would any public purpose program cost that did not specifically relate to demand response be included (Question #9). Exactly matching the temporal variance of costs in rates would best achieve the theoretical objectives of time varying rates (Question #10). However, departures from this theoretical ideal may be deemed necessary, as discussed above in Section 1.

Question #6: If a time variant rate requires market price information, will the rate information be required from the California Independent System Operator's (CAISO) Market Redesign and Technology Update (MRTU)?

DRA Response: Market information from the CAISO will be required. However, the main emphasis of MRTU is nodal and congestion pricing, and nodal information is likely to be aggregated in retail electric rates. Thus, though it is not inherently necessary to await MRTU coming on line to implement time-varying rates with relatively high granularity (e.g., hourly), it may make sense to wait given how imminent it is. As discussed further above in Question #1 of Section 2.

Question #7: Should some costs be recovered through a flat customer charge, demand charge, and/or non-varying per kW-hour charge?

DRA Response: Some rate designers would advocate recovering relatively fixed costs through charges that do not change with changes in consumption. However, others would say that a strict marginal cost pricing scheme should exclude such fixed or sunk costs, since they are not marginal in the short-run. In a regulated utility, this requires increasing the EPMC multiplier to a level where some would say the marginal cost signal is lost anyway. Thus they would say that recovering fixed costs through volumetric and time-varying kWh charges would lead to *more* energy conservation and demand response than is optimal. But, as noted in the answer to question #1 in section 1, the inclusion of such costs in a volumetric rate can be justified on the grounds of externalities not included in the marginal cost. In the residential sector, there has been a long history of recovering almost all costs in volumetric rates, and DRA supports continuing this philosophy.

Question #8: Should the components of the rate that are collecting fixed costs vary over time? If so, how should fixed costs be allocated to different time periods?

DRA Response: See answer to question #5.

Question #9: How should the costs for public purpose programs and other non-bypassable charges be reflected in the time-variant portion of rates, if at all?

DRA Response: See answer to question #5.

Question #10: What balance between fixed and time-variant costs will achieve the objectives of the tariffs?

DRA Response: See answer to question #5.

Question #11: Should direct access and CCA customers be able to participate in time variant rates?

DRA Response: The Commission has no authority to dictate how CCA providers should structure their rates.

Question #12: If a rate is intended to reduce load in the face of a short-term supply shortfall, should the design of the rate differ depending on whether the shortfall is forecast on a day-ahead or day-of basis?

DRA Response: Since the day-ahead price gives the customer relatively more price certainty than a day-of price, the customer should be required to pay for that certainty. Accordingly, some kind of hedging premium should be built into the rate. But it would be a much smaller premium that what would be built into a flat rate.

4. Recovering the revenue requirement

This is an important part of the rate design discussion, but unfortunately one that should wait until more discussion takes place on the rate design itself. This is because different rate designs will entail different potentials for over and undercollections. A two-part RTP rate, where the second part exactly mirrors the utility's short-term procurement costs, theoretically would involve relatively small over and undercollections. They also would not require forecasting in advance the customer's response to rates (Question #3) since they are exactly charged for what they consume. Thus they also would not require the use of price elasticity estimates (Questions #4 and #5). But there are complications with two-part RTP rates, discussed in Section 6 below.

In contrast, over- and under-collections are very likely when part of the equal percentage of marginal cost ("EPMC") multiplier and costs that are only variable over time periods greater than the rate cycle are embedded in the time-varying portion of the rate. Such rates will require ratemaking mechanisms that track and adjust for deviations between the revenues collected and actual costs. Establishing subaccounts in the Energy Resource Recovery Account ("ERRA") is one possibility (Question #8).

Question #1: How can rates be designed to both recover the revenue requirement and communicate price information?

DRA Response: Even though most rates have to be adjusted away from marginal costs to recover the revenue requirement, some semblance of the marginal cost price signal remains. For example, the relative size of different rate elements can still be proportional to the underlying marginal costs.

Question #2: How can rates be designed to avoid large periodic rate adjustments to recover revenues?

DRA Response: Variations in rates can be reduced if they could automatically adjust on a monthly level for changes in the cost of natural gas and other major drivers of procurement costs that vary in the short run. Currently natural gas prices to retail customers change monthly. One disadvantage of changing the retail price monthly is that it is difficult for customers to know in advance what they are paying. Thus any move to monthly pricing on the electric side should include, at a minimum, dissemination of forecasts of anticipated prices on the internet before the change takes place. Preferable would be the broadcasting of such information in a form that could be received by home area networks.

Question #3: Does the utility need to be able to forecast accurately the response of customers to these differential rates?

DRA Response: Certain rate designs, such a two-part RTP, where customers are exactly charged short-run marginal cost in the second part, will not create a revenue over- or under-collection. Thus there is little need to accurately forecast customer response to such tariffs. This need is also reduced if mechanisms can be developed to adjust rates depending on customer response.

Question #4: Do the utilities need reliable estimates of price elasticities of demand for customers to make sales projections?

DRA Response: Price elasticities are only critical when it is important to accurately forecast customer response. As indicated in the answer to question #3 above, it may be possible to structure rates or create regulatory mechanisms that reduce the need for accurate forecasts.

Question #5: What estimates of price elasticities exist and can be relied upon for rate design purposes?

DRA Response: Currently the best source of elasticities is the Statewide Pricing Pilot ("SPP").[6] As dynamic rates are implemented, further study of elasticities may be necessary.

Question #6: If customer responses to dynamic pricing tariffs result in revenue over- or under-collections, should the over- or under-collection be addressed by adjusting rates within the customer's class, or should the over- or under-collection be addressed by adjusting rates for all customer classes?

DRA Response: DRA is not opposed to resolving over- and under-collections within the class as long as that class can also be given credit for the reduction in system procurement costs it has achieved. But this is often difficult. This is one reason why interruptible rate credits are not paid for entirely by the class which is offered such credits.

Question #7: If customers' self-selection into voluntary dynamic pricing tariffs results in over- or under-collections, how should the over- or under-

[6] Charles River Associates, Statewide Pricing Pilot, 2004. (authorized by D.03-03-036)

collection be recovered—by adjusting rates of customers taking service under the voluntary tariff, by adjusting the rates of all customers within the customers' class, or by adjusting rates for all customers?

DRA Response: Whether over- or under-collections should be born by the class or by individual rate schedules is a subset of the problem addressed in question #6. Thus DRA's answer would be the same.

Question #8: What mechanisms should the utility use to recover over- and under-collections from customers?

DRA Response: In the SDG&E GRC, subaccounts to the ERRA have been discussed as a way to recover over- and under-collections.

Question #9: Should dynamic pricing tariffs be revenue-neutral with respect to flat and less time differentiated tariffs, or should the revenues collected by dynamic pricing tariffs differ from the revenues collected by flat and less time differentiated tariffs due to the incorporation of hedging premiums or participation credits?

DRA Response: As long as the tariff is expected to be cost effective in terms of reducing system electricity generation costs more than the cost of the participation credits, they could be funded outside of the dynamic tariff.

Question #10: If the incorporation of hedging premiums or participation credits results a revenue over- or under-collection, how should the revenue over- or under- collection be treated?

DRA Response: In general, customers should pay for whatever price certainty is being provided to them, and the cost of any hedging should be built into their rates. However, under-collections could occur in cases where it is difficult to separate out the cost of hedging from the utility's generation portfolio and charge it to customers who are on relatively flat rates. Such under-collections may have to be borne by all customers. Regarding participation credits, under-collections could be funded by all customers as long as there is a commensurate reduction in generation costs. Otherwise, they should be recovered from the class of customers receiving those credits.

Question #11: If the average cost to serve customers on a particular dynamic pricing tariff is less than the cost to serve customers not on the tariff, can the tariff be structured so that the dynamic pricing customers have a lower average cost?

DRA Response: If the additional cost of providing customers a certain level of price stability can be identified and separated from the utility's system generation costs, that additional cost should be allocated to customers that are on flat rates. The same amount could be subtracted from whatever system generation costs are allocated to the dynamic rate schedules since they are not receiving the same level of price stability as are those on flat rates. A hedging premium based on wholesale market prices could be a proxy for this amount (see Section 5 below).

Question #12: If the utility incurs incremental costs to implement dynamic pricing tariffs (e.g. administrative costs, equipment, education), how should the incremental costs be recovered?

DRA Response: Given the purpose of such tariffs is to reduce generation costs for all customers, the costs should be allocated to all customers.

5. Hedging

A hedging premium is a very important complement to dynamic rates and should be offered. Calculating a hedging premium is a major challenge. Approaches are available similar to that described in Appendix 2 of the Demand Response Research Center ("DRRC") paper which partly rely on the varying prices of different products (spot, forward contracts, etc.) available in the wholesale market.[7] More investigation of how to calculate a hedging premium using actual wholesale market data in this phase of the proceeding would be very useful.

Question #1: Should customers have the opportunity to hedge the price risk under some or all of the dynamic tariff options?

DRA Response: Yes.

Question #2: Should hedging options be offered by the utility, or should rates be structured so that hedging can be obtained externally in the marketplace?

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[7] The Brattle Group and UtiliPoint "Rethinking Rate Design", prepared for the DRRC, Lawrence Berkeley National Laboratory, August 7, 2007, Appendix B.

DRA Response: Given that it is unclear whether the external market will make such products available, the utilities should be prepared to offer such products initially.

Question #3: If a hedging premium is incorporated into relatively flatter rates, what should the premium be and how should it be determined?

DRA Response: DRA would be in favor of incorporating a hedging premium into flat rates. But this raises major complications in terms of how the revenue requirement would be allocated between dynamic and flat tariffs. This is because different tariffs are dynamic to different degrees, with traditional TOU rates being slightly more dynamic than flat rates and RTP rates being highly dynamic.[8] Presumably the hedging premium would reasonably reflect what the utilities actually pay for price certainty, which may be quite high given the current resource adequacy requirements, as discussed in Section 6 below. Theoretically, one would want none of these costs allocated to a highly dynamic tariff, with the revenue shortfall allocated to the other tariffs. Any study of a hedging premium in this phase should include how the cost of such a premium could be allocated to different tariffs.

Question #4: Should customers have the opportunity to hedge through a two-part tariff in which part of their consumption is purchased at a fixed rate and the rest is purchased at the dynamic rate?

DRA Response: Yes.

6. Sources of triggers and prices for dynamic prices

In setting dynamic rates, it should be noted that the wholesale market is changing in such a way that energy prices are not currently showing much variation between the five TOU periods currently used for commercial and industrial TOU rates.[9] Adding a CPP period helps, but beyond that, the tariff may

[8] There is some confusion about what actually constitutes a dynamic tariff, with some saying that TOU rates are not dynamic because they are determined in advance of knowing market conditions. They do, however, reflect the *potential* of what can happen in the market during different time periods and thus can be regarded as a proxy for a dynamic rate.

[9] Residential TOU rates generally have fewer TOU periods. PG&E's Schedule E-6 tariff only has four TOU periods (on and off-peak for both summer and winter).

become too complicated for customers without enabling equipment. What is primarily changing the wholesale market is the imposition of resource adequacy requirements. This is causing a trend where producers recover relatively more of their costs through capacity contracts and call options than they do through their energy prices than has been the case in the past. A centralized capacity market (see Question #4), if one gets implemented, will further this trend.

What this means is that the true cost of reliability is captured in neither the traditional calculation of marginal energy costs nor the cost of capacity. The cost of capacity is generally reflected in marginal cost studies using a CT proxy. Yet the CT cost might be lower than what utilities actually pay for capacity. Rate designers in general do not have a good handle on this issue because actual utility procurement cost data have been excluded from rate design proceedings on confidentiality grounds. If this phase of the proceeding could resolve this disconnect between rate design and what's really happening, that would greatly further the cause of accurately time-differentiating rates in dynamic tariffs. Granted these capacity contracts and call options are themselves fixed costs once the utility enters into such contracts. But it may make sense to time differentiate them using relative loss-of-load probabilities ("LOLP") as is currently done with the CT.[10]

Question #1: For trigger-based rates such as CPP, who should determine when an event is triggered—the CAISO or the utility?

DRA Response: Both the utility and the CAISO should be involved in determining when an event is triggered. The CAISO has a broader perspective of the energy demand-supply balance than does the utility. But the AMI systems will likely be set up so that it is the utility that would notify customers of such events. The utility knows best the loads on its individual feeders and whether the

[10] This recent development also calls into question whether RTP rates currently make sense given that a major part of the time-differentiation in rates could be determined in advance using an LOLP model.

distribution system is in danger. The utility also can control the number of events to remain within the constraints imposed by the tariffs. Thus, at a minimum, coordination is required between the two.

Question #2: Should RTP be linked to wholesale market prices or some other price or cost information?

DRA Response: Ideally, RTP should be linked to the wholesale price. But, as discussed, wholesale capacity contract costs are fixed once entered into and do not vary by hour. They should be allocated to hours in some manner and included in the RTP price.

Question #3: If a RTP rate is linked to wholesale market prices, what wholesale market prices should the tariff be linked to?

DRA Response: As discussed above, RTP must be linked to both spot energy prices as well as the cost of fixed capacity.

Question #4: What impact will MRTU and potential capacity market implementation have on the prices used to design RTP and other dynamic tariffs?

DRA Response: The emphasis of MRTU is on establishing nodal and congestion pricing. Since utility retail rates will likely reflect a weighted average of prices on all the transmission nodes at which the utility takes service, MRTU likely will not affect a utility's time differentiated rates in itself. But it will complicate communicating that time-differentiated price to the customer on a real time basis (see answer to Question #1, Section 2). The introduction of a centralized capacity market will likely suppress the time variation in energy prices. This will make inclusion of the costs of capacity in RTP necessary.

Question #5: Will the variation in wholesale market prices impact customer behavior?

DRA Response: The variation in wholesale energy prices is currently not enough to affect customer behavior, and this variation would decrease with the introduction of a centralized capacity market. Whether wholesale capacity prices will affect customer behavior depends on how they are allocated to time period and how granular those time periods are. Less granularity tends to smooth out price difference observable at a greater level of granularity. Broad TOU periods such are currently defined in TOU tariffs may not be granular enough to evoke a response. CPP rates will evoke a greater response, especially if the actual wholesale capacity price is higher than a CT price.

Question #6: Should tariffs be tied to the day-ahead or the same-day real time price?

DRA Response: Whether prices should be tied to the day-ahead or same-day price depends on the ability of customers to react to same-day prices. This depends on the availability of enabling equipment. It also depends on whether same-day prices can be communicated to such enabling equipment.

Question #7: How should the real time price be communicated to customers?

DRA Response: There are no proposals to transmit such information through the AMI systems, though it is theoretically possible to do so. Alternatively, such information could be broadcasted over the FM Radio Data System ("RDS") subcarrier. The California Energy Commission ("CEC") Title 24 programmable communicating thermostats will be capable of receiving CPP notification through RDS.

Question #8: Should the RTP rate be a two-part rate with both a fixed price portion for part a customer's usage and a dynamic portion for the remaining usage?

DRA Response: Yes, it would make sense to implement RTP as a two-part tariff given the uncertainty of how to include in it wholesale capacity prices. But, in general, there are pros and cons related to two-part RTP tariffs. A pro is that it allows the best matching of the utility's revenues and costs (See Section 4 above). A major disadvantage is that of how to establish a customer reference level for a new customer where there is no history of consumption (Question #9). This requires discussion and negotiation between the customer and the customer service representative which would be administratively burdensome if implemented for small customers. Another major challenge is the fact that marginal energy costs are currently lower than average rates. Thus a true two-part RTP tariff, where the second part only reflects costs that vary in the very short run at the margin, may actually encourage consumption. This might be at odds with the Commission's energy conservation and greenhouse gas reduction goals.

Question #9: Under a two-part RTP rate, how should a customer's reference level for the fixed portion be determined?

DRA Response: Generally this should be based on an analysis of the customer's historical usage. But discussion between the customer and customer service representative is needed in case changes in a customer's operations are anticipated that can alter electricity usage. Such changes may not be known by the utility without such a discussion. This kind of dialogue and analysis of the customer's historical usage must be done on a case by case basis, making a two-part RTP tariff practical only for the very large customers. If the customer is new, and there is no historical usage, the usage per square foot of similar businesses can be used, but this is highly prone to error. Such a tariff should be voluntary, and perhaps only those who have been customers for at least one or two years should be allowed to sign up.

Question #10: Under a two-part RTP rate, what costs should be recovered in the fixed portion of the rate?

DRA Response: Generally, two part tariffs aim to recover in the first part of the rate the entire embedded cost associated with the customer's usage at the customer reference level. Thus only short-run marginal procurement costs are included in the second part. If a tariff is designed to recover something closer to the embedded cost in the second part, then regulatory adjustment mechanisms will be needed to cover the revenue over- or under-collections.

7. Residential Rate Issues

Footnote 5 on page 7 of Attachment A of the ACR states that D.06-10-051 finds that *optional* dynamics rates are not prohibited by AB 1X. In spite of this, two of the utilities (SCE and SDG&E) have shied away from offering CPP rates to the residential class. They have opted instead for PTR programs in which *all* residential customers can be automatically enrolled without violating AB 1X. This maximizes participation relative to what is possible under a voluntary CPP rate (Question #3).

While PTR has problems that have been discussed at length in both the SDG&E AMI and GRC proceedings, DRA currently favors offering this program during the initial AMI rollout. It starts AMI off on a positive note by offering only rebates and no penalties, and provides a certain level of education since all customers will automatically be enrolled. If the Commission wishes to go further before AB 1X sunsets, it might consider developing a "straw man" proposal where rates in Schedule E-1 above tier 2 are converted to TOU periods. Such a rate design was offered by DRA in its PG&E AMI testimony where one of the TOU periods was a CPP period. This rate design preserves the energy conservation features of the current rate design by retaining a tier structure. It is also considerably simpler than the existing PG&E TOU rates which have tiers in all the TOU periods, resulting in 20 different rates depending on the tier and TOU period for Schedule E-7.

Several questions ask about what rate design could be offered after AB 1X sunsets. DRA cautions the Commission that any rate design for the residential class must still comply with the baseline legislation (Public Utilities Code Section 739). While AB 1X is emergency legislation, the baseline legislation has been State policy for over two decades. That legislation states that a baseline amount of electricity equal to 50% to 60% of average residential usage, within an increasing block rate structure, must be provided at a discounted rate. DRA advocates offering this amount at the same flat rate regardless of time of day. As discussed further in response to question #2 below, all usage above the baseline level could be subject to the baseline rate plus an energy surcharge (that would be flat) and a capacity surcharge (that would vary seasonally and by time of day).

Question #1: What dynamic rates should be offered to residential customers while the rate protection offered under AB 1X remains in effect?

DRA Response: As indicated above, the Commission should start with PTR and then transition to an AB 1X compatible default Schedule E-1 time-differentiated rate.

Question #2: What types of dynamic rates can be offered to residential customers if the AB 1X rate protection is lifted by the Legislature or is no longer effective?

DRA Response: As stated above, DRA believes that the baseline legislation, while perhaps not explicitly *requiring*, nevertheless sets a strong precedent for offering a minimum amount of energy at a flat rate. We also advocate a tiered structure after AB 1X sunsets. Thus the basic rate design after AB 1X expired, for the usage protected by that legislation, would not look all that different from what currently exists.

As discussed above, DRA proposes that, after AB 1X sunsets, usage above the baseline level be subject to the baseline rate plus an “energy surcharge” and a "capacity surcharge". A very simple rate design would only levy the capacity surcharge in the on-peak period. Alternatively, several differently sized capacity surcharges could be adopted for different time periods, including a CPP period. The baseline legislation does not explicitly say how much of a discount should be offered on baseline usage. But DRA recommends basing all rates on an EPMC scaling of those costs that would be reflected in the baseline rate and those that would be reflected in the two surcharges. The later would be the marginal cost of capacity (reflected in the capacity surcharge) and the cost of public purpose programs, pollution credits, and externalities (reflected in the energy surcharge). All other marginal costs would be reflected in the baseline rate.

To maximize the usage that would be subject to the energy and capacity surcharges, the Commission could reduce the baseline quantities to the minimum allowed by law.[11] To prevent large under-collections, this rate would become the default rate schedule in the residential class.[12] In order to transition to such a rate schedule, the Commission might consider time differentiating all usage above tier 2 while AB 1X is still in effect. DRA proposed such a rate design in its PG&E AMI testimony.[13]

Question #3: How can rates be designed to maximize residential participation while the AB 1X rate protection remains in effect?

DRA Response: See Use of a PTR program would maximize participation.

Question #4: To what extent do existing residential rates and programs such as increasing block rates and air conditioning cycling fulfill the Commission's policy goals?

DRA Response: A/C cycling is effective in reducing demand, but there is a question about whether it is redundant with the AMI system (see answer to question #6 below).[14] Increasing block rates may also be effective in reducing

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[11] Shortly after AB 1X was enacted, customers consuming in the higher tiers reacted to the dramatically higher prices they were being charged. The Commission, in response to this reaction, increased the baseline level for the three utilities to close to the maximum prescribed in the baseline legislation. This has the effect of putting more of large customers' usage into the range that received AB 1X protection.

[12] PG&E has expressed concerns to DRA that such a rate, if introduced on a voluntary basis, would result in flat-load customers adopting it, while peaky-load customers stay with the flat rate. Such a scenario could produce a serious under-collection.

[13] DRA Opening Testimony in A.05-06-028, Chapter 3.

[14] Currently, dynamic rates are economically dispatched demand response programs and A/C cycling is a reliability program. Eventually, when more experience is gained of how customers

(continued on next page)

peak demand because, as stated below (see answer to question #5), they are a proxy for TOU rates. Increasing block rates are certainly also very effective in reducing energy consumption given how steeply they currently are inverted. Energy conservation will probably more greatly reduce greenhouse gas than demand response or dynamic rates will.

Question #5: Could additional demand response be provided if AB 1X rate protection were no longer effective? If so, how much additional demand response? What would the potential bill impact be for residential customers if they were able to participate in dynamic pricing rates?

DRA Response: DRA finds this to be a moot question because AB 1X is still law. Nevertheless, how much additional demand response could be obtained remains uncertain because consumption in the upper tiers tends to occur more in the summer on-peak period. As discussed in DRA's PG&E AMI rebuttal testimony, 46% of the summer consumption of PG&E customers who consume into those tiers is in the on peak period. This compares with 26% for customers who only consume into tier 1.[15] This makes the current rate structure a proxy for a TOU rate. As for whether more demand response could be elicited from smaller customers who do not consume above tier 2, it is unclear whether such customers have as much discretionary usage that they could curtail if a dynamic rate were imposed on them. DRA addressed this issue in its SDG&E GRC residential rate design testimony.[16]

Question #6: How would existing residential rates and programs such as increasing block rates and air conditioning cycling be affected by dynamic pricing rates for residential customers?

DRA Response: Currently, dynamic rates essentially are economically dispatched demand response programs and A/C cycling is a reliability program. Eventually, when more experience is gained of how customers respond to dynamic rates, they could replace A/C cycling as a reliability program. But this possibility is probably several years away.

Question #7: Should low-income residential customers be offered discounted dynamic rates or other dynamic rate options?

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respond to dynamic rates, they could replace A/C cycling as a reliability program.

[15] DRA Rebuttal Testimony in A.05-06-028, Chapter 5.

[16] See DRA's Opening Testimony in A.07-01-047, Chapter 3.

DRA Response: DRA believes low income customers should certainly be offered discounted dynamic rates once AB 1X sunsets. Again, this is a moot issue at this stage. But, where CARE tier 3 rates exist, the third tier could now be time-differentiated even before AB 1X sunsets. DRA finds the DRRC proposals to charge low income customers the full rate and provide the subsidy in some other way unworkable.[17] Fairness dictates that the size of the discount be proportional to the household size and housing type, information which is not readily available for CARE customers. Energy usage is a reasonable proxy for these household characteristics, and the current tariff bases the discount on energy usage. Every kWh of CARE usage is discounted, and the discount is larger the more a customer consumes. Whether this discount encourages wasteful consumption is unclear given that the marginal utility of a dollar is much higher for a person who doesn't have as much money as the average customer. Also, CARE customers, on average, consume less than non-CARE customers.

8. Critical Peak Pricing

All the questions in this section are being addressed in the rate design proceedings. The one issue brought up in this section that would be fruitful to pursue further in this phase is that of how the CPP price is set. This is the focus of Question #1, which also asks whether there might be a reliability value that is not included in wholesale power prices. Most of the other questions involve issues that are not ready for "prime time".

Question #1: What should a CPP rate be based on? Is there a reliability value that is not included in wholesale power prices that should be incorporated into the tariff?

DRA Response: The CPP price is currently not based on wholesale power prices, and if it were, there is a question of what wholesale power prices to use. As discussed in Section 6 above, wholesale *energy* prices currently do not reflect the cost of reliability and thus are fairly flat across time periods.

The CPP price is currently based on a CT proxy. Generally, to make the CPP rate large enough so that customers will respond, rate designers have found it necessary to reflect the entire cost of the CT in the few summer hours which fall

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[17] The Brattle Group and UtiliPoint, Ibid. Ch. 3

into the CPP period. This is done even though there are many hours outside of that period where a CT potentially could be dispatched. As discussed in Section 6 above, the CT proxy may not be a good reflection of what utilities are actually paying for capacity. If something other than the CT proxy were used, then it might not be necessary to assign the entire capacity cost portion of the rate to the CPP period alone.

Question #2: How long should the critical peak period be?

DRA Response: As for the length of the CPP period (Question #2), this is generally based on a review of the individual utility's load variations. This topic would be difficult to discuss on a generic level in this proceeding.

Question #3: When should a utility be able to trigger a critical peak period—during summer peak hours only, during summer mid-peak and off-peak hours, during winter hours?

DRA Response: Eventually, as we gain more experience with CPP programs, it may make sense to expand the CPP period beyond summer hours and allow for CPP periods that are not confined to a fixed number of hours per event (pursuant to Question #4). The latter, however, will have to await enabling equipment because it would be difficult for customers to keep track of variable-length CPP periods that can occur at any time of the year.

Question #4: How can a CPP tariff be structured to allow for a variable number of events each year while still recovering the revenue requirement?

DRA Response: A CPP tariff is usually designed to collect whatever revenue requirement is allocated to that schedule through a pre-determined number of events. If the actual number of events differs, then ratemaking mechanisms must be designed to track the revenue under- and over-collections. Ratemaking mechanisms to track a variable number of RTP and CPP events are being discussed in the SDG&E GRC. It is anticipated that they will be subaccounts of the ERRA.

Question #5: Is the potential customer savings or cost great enough under a CPP rate to motivate a customer response?

DRA Response: As indicated in the answer to question #1 above, rate designers often load the entire cost of the CT into the CPP rate in order to create a rate high enough to invoke a customer response. This is often done without reducing coincident demand charges (which are supposed to recover the cost of capacity) to zero. As indicated above, this inconsistency in CPP rate design could be addressed through further investigation into the true cost of capacity.

9. Relationship to reliability oriented and other demand response programs

This section of the ACR contains ten questions about the relationship between dynamic rates and demand response programs. DRA does believe that dynamic pricing could eventually replace reliability oriented programs (such as interruptible rates and A/C cycling) once more is known about how customers respond to dynamic pricing (Question #2). But this possibility is probably several years away for the residential class. Dynamic rates allow the customer more control over their usage than programs where the utilities call the events, which is favorable.

Question #1: What is the purpose of reliability-oriented demand response tariffs and programs such as interruptible rates and programs and air conditioning cycling?

DRA Response: The current purpose of the current reliability-oriented demand response programs is to provide "insurance" coverage in the event of stage 2 and stage 3 emergencies. With RAR guidelines, the probability of such events is decreasing, calling into question the cost effectiveness of such insurance. Thus there has been discussion about only paying incentives when such programs are called upon, causing them to morph into something that more closely resembles an economic dispatch. The line between reliability programs and economic programs is beginning to blur.

Question #2: To what extent can dynamic pricing rates provide the reliability benefits that are provided by reliability-oriented tariffs and programs?

DRA Response: As indicated above, DRA believes that dynamic pricing could eventually replace reliability oriented programs (such as interruptible rates and A/C cycling) once more is known about how customers respond to dynamic pricing. But this possibility is probably several years away for the residential class. Dynamic rates allow the customer more control over their usage than programs where the utilities call the events, which is favorable.

Question #3: Should customers have the option to simultaneously participate in dynamic pricing tariffs and interruptible or other reliability programs?

DRA Response: Yes, if proper rules are applied, as discussed in the answer to question #4 below.

Question #4: When simultaneous participation is allowed, what rules are needed to minimize overpaying customers for demand reductions?

DRA Response: If customers participate in both dynamic pricing tariffs and interruptible or other reliability programs (Question #3), either the dynamic rate or interruptible credit must be structured so that the customer does not double collect the avoided cost of its capacity savings. This issue has been addressed in prior GRCs. One problem with adjusting the dynamic rate is that the resulting price signal generally shows insufficient time differentiation to invoke a customer response. DRA has proposed marketing air conditioning cycling as a way of enabling an automatic response to CPP rates and not paying the normal credit for air conditioning cycling if the customer also signs up for CPP (Question #4).[18]

Question #5: Should customers have the option to simultaneously participate in dynamic pricing tariffs and other price-responsive programs?

DRA Response: Yes. See answers to questions #3 and #4 above.

10. Timing of tariff development and roll-out

As indicated in Section 1, DRA favors the Commission moving slowly in introducing time-differentiated tariffs. The critical factors behind our preference are the timing of the AMI rollout (Question #3) and the availability of enabling technology (Question #4). PG&E's AMI system will not be fully deployed until 2011 and SCE's not until 2013.

Question #1: When should time-differentiated tariffs be introduced for each customer class?

[18] See A.07-04-009, DRA's Opening Testimony on September 17, 2007 at pages 19 – 20. TURN has proposed prohibiting simultaneous participation in both programs (See TURN's opening testimony in the same proceeding at page 9).

DRA Response: Simple dynamic tariffs should be introduced on a voluntary basis during the time when the meters are being installed. Once all the meters are installed, and enabling equipment becomes available and customers become more educated about dynamic rates, then a more comprehensive set of dynamic rates can be offered. Opt-out and mandatory programs should not be adopted until all customers have interval meters. This situation currently exists for customers over 200 kW in load.

Question #2: Does the detailed development of some time-differentiated tariffs need to wait until after the CAISO's MRTU is on-line?

DRA Response: Tariffs such as RTP, that are highly dynamic, should wait until price information can be communicated quickly and easily to customers. Though hourly rates are currently shown on the CAISO's website, these will become dramatically more complex once MRTU goes on line. Given that this will happen next year, and anything adopted now would merely be an interim measure, it might be better to wait for more wide scale deployment of such tariffs.

Question #3: How does the meter installation schedule for small commercial and residential customers affect when tariffs should be introduced?

DRA Response: It makes little sense to adopt tariffs that can significantly penalize low load factor customers or that result in large revenue shifts between customers while the meter installation is taking place. In the interim, a simple PTR program, where every customer automatically participates, will maximize customer exposure to dynamic rates and their education. After all the meters are installed, and home area networks become more standardized and available, then more wide spread deployment of TOU and CPP rates can be contemplated.

Question #4: Should customers be given time before the implementation of new time-differentiated tariffs so that customers may make technological and operational changes to benefit from the new tariffs?

DRA Response: Yes. See the answer to question #3 above.

III. Conclusion

The advent of AMI provides genuine opportunities for innovative rate design in California. The need to more accurately reflect the cost of capacity in rates is also becoming increasingly important given how California's load factor has declined in recent rears. Thus DRA supports innovation in rate design provided it is done slowly and after much analysis and deliberation. There are major challenges in determining how this new technology can best be used. Above all, the temptation to see dynamic pricing as more important than all the considerations that have gone into existing rate design must be avoided. The goals of energy conservation (regardless of time of day) and protecting smaller customers with fewer resources, which are built into current residential rate design, remain worthy goals.

Respectfully submitted,

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October 5, 2007

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of "" in A.06-03-005 by using the following service:

[X] **E-Mail Service:** sending the entire document as an attachment to an e-mail message to all known parties of record to this proceeding who provided electronic mail addresses.

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Executed on October 5, 2007 at San Francisco, California.

/s/ Imelda C. Eusebio
Imelda C. Eusebio

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